Available online at www.sciencedirect.com
SCIENCE DIRECT
Renewable and Sustainable Energy Reviews
8 (2004) 521–544
RENEWABLE & SUSTAINABLE ENERGY REVIEWS
www.elsevier.com/locate/rser

The use of sustainable combined cycle technologies in Cyprus: a case study for the use of LOTHECO cycle

Andreas Poullikkas *, Adonis Kellas

Electricity Authority of Cyprus, P.O. Box 24506, 1399 Nicosia, Cyprus

Received 12 January 2004; accepted 20 January 2004

Abstract

In this work, a cost–benefit analysis concerning the use of the low temperature heat combined cycle (LOTHECO cycle) in Cyprus is carried out. Also, the expected main emissions from the LOTHECO cycle are compared with existing commercial technologies. In particular, the future generation system of Cyprus power industry is simulated by the independent power producers optimization algorithm and by the long-term expansion software Wien Automatic System Planning. Various conventional generation options are examined and compared with LOTHECO cycle parametric studies. The economic analysis, based on the assumptions used and the candidate technologies examined, indicated that in the case of conventional technologies the least cost solution is the natural gas combined cycle. Additional computer runs with the various LOTHECO cycle parametric studies indicated that for efficiencies greater than 60% and capital cost between 700 and 900 €/kW, LOTHECO cycle is the least cost generation technology. Furthermore, the current state and future improvements of the environmental indicators of the power industry in Cyprus are presented. It is estimated that by the use of LOTHECO cycle instead of the business as usual scenario, the principal environmental indicators would be reduced by the year 2010 by approximately −23% instead of −8%. Further, the carbon dioxide environmental indicator will be reduced by +24% instead of +68%.
© 2004 Elsevier Ltd. All rights reserved.

Keywords: Power generation; Gas turbine; Combined cycle; LOTHECO cycle; Cost–benefit analysis

* Corresponding author. Tel.: +357-22-333600; fax: +357-22-333176.
E-mail address: mspoul@ucy.ac.cy (A. Poullikkas).

1364-0321/$ - see front matter © 2004 Elsevier Ltd. All rights reserved.
doi:10.1016/j.rser.2004.01.008

Contents

1. Introduction

The energy industry is undergoing a turbulent state of transition. Markets are being open up, the industry is globalizing, competition is tightening and new players are entering the market. The deregulation of the electricity industry, which has began not more than 10 years ago, is giving way to a global trend toward the commoditization of electric energy. This trend has recently intensified in Europe and North America, where market forces have pushed legislators to begin removing artificial barriers that shielded electric utilities from competition [19].

Unlike other commodities, electricity cannot be stored. Therefore, a delicate balance must be maintained between generation and consumption; 24 h a day, 7 days a week, 8760 h a year. Electric power may be generated from natural gas, coal, oil, nuclear fuel, falling water, geothermal steam, alternative resources such as cogeneration, and from renewable resources such as wind power, solar energy and biomass [14]. Although the principles of generating electricity are simple, the power system balancing process is complex.

Prior to electric industry restructuring, electric utilities transferred power to one another using their transmission system [12]. Presently, anyone who owns transmission facilities, or who has firm contractual rights to use transmission facilities to be operated by the system operator, is referred to as a transmission owner. These transmission owners calculate and monitor transmission line capacities in order to avoid line overloading and possible damage to equipment [7,12].

Prior to liberalization, a typical power company had the legal monopoly to supply customers within its geographic region with electricity. As a consequence, these companies either built power stations to meet their own demand or entered into long-term supply contracts for the provision of power by third parties [17,18]. The liberalization of the electric power market, however, leads to a stronger competition among electrical utilities. The competitive market will attract independent power producers and a trend that will emerge is the decrease of the average plant size. New power plants will be in the 300–350 MWe size range, or possibly smaller, bringing a more efficient distribution of power.

Currently, under the cost pressures of liberalization, combined cycle plants using natural gas show a competitive edge over conventional thermal plants as they have lower investment costs, shorter lead times and can operate at a fraction of personnel costs. Combined cycle technologies will play a major role, as the power plant construction market picks up. However, gas prices are strongly dependent on world markets and are coupled with oil prices, so this is a factor of uncertainty [19]. The outstanding features of combined cycle power plants become more attractive with their increasing utilization power market. These features include high efficiency in utilizing energy resources, low emissions, short construction period, low initial investment cost, low operation and maintenance cost, and flexibility of fuel selection. Thus, combined cycle power plants are quite competitive in the power market. The combined cycle plant is a combination of two different technologies, that is, the gas turbine and the steam turbine. The heat of the exhaust gas from the gas turbine is used to raise steam in the heat recovery steam generator for the steam turbine. Nowadays, advanced combined cycle plants can reach a thermal efficiency up to 58% [6].

The low temperature heat combined cycle (LOTHECO cycle) [2], shown in Fig. 1, uses a mixed air steam turbine, as a topping cycle, with an external energy source for the water-in-air evaporation (e.g., solar energy). The heat contained in the exhaust gas is utilized in a bottoming Rankine cycle. Since the water-in-air evaporation takes place at the vapour partial pressure, the saturation temperature is accordingly significantly low (below 170 °C). This temperature range (from below 100 up to 170 °C, depending on the amount of injected water and the compressor pressure ratio) is in favour of the integration of low-quality heat sources, which under other circumstances cannot be utilized for electric power generation, such as, geothermal, solar, etc. These arrangements result in an enhanced fuel-to-electricity efficiency compared to the efficiency of an equivalent conventional combined cycle. Efficiencies above 60% have been recently reported [2].

In this work a cost–benefit analysis is carried out concerning the use of LOTHECO combined cycle for power generation and compared to the conventional power generation technologies. In particular, an economic study concerning the use of the LOTHECO cycle by independent power producers in Cyprus is carried out using the independent power producers (IPP) optimization algorithm [16] and comparisons are made through the commercial software Wien Automatic System Planning (WASP) [10]. Further, the expected main emissions from the LOTHECO cycle are compared with that from the existing commercial technologies.

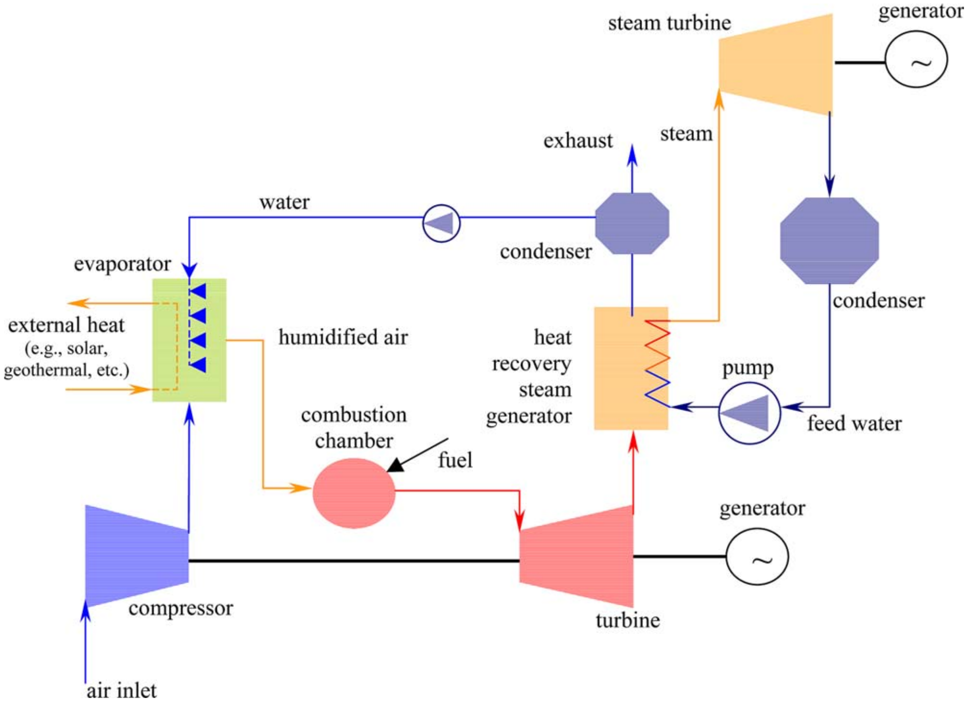

Fig. 1. The LOTHECO cycle.

In Section 2, the Cyprus power system is described and in Section 3, the load forecasting is presented. The simulation of the power system by a commercial widely used software is outlined and discussed in Section 4 and the results obtained by the independent power produces algorithm are presented in Section 5. The current state and future improvements of the environmental indicators are presented in Section 6. The conclusions are summarized in Section 7.

2. Cyprus existing power system

For many decades the power industry in Cyprus developed on the basis of available technology and know-how, and today it constitutes a key sector of the economy. The Electricity Authority of Cyprus (EAC), which is a non-profit semi-governmental organization, is responsible for the generation, transmission and distribution of electricity in Cyprus.

The Cyprus power system (Fig. 2) operates in isolation and at present consists of three thermal power stations with a total installed capacity of 988 MWe. Moni power station consists of 6×30 MWe steam turbines and 4×37.5 MWe gas turbines and is located on the south coast of Cyprus, to the east of Limassol. Dhekelia power station consists of 6×60 MWe steam turbines and is located on the southeast coast of Cyprus, to the east of Larnaca. Vasilikos power station con-

Fig. 2. Location of EAC power stations.

sists of 2×130 MWe steam turbines and one 38 MWe gas turbine. The steam units at Vasilikos are used for base load generation, while the steam units at Dhekelia are used for base load and intermediate load generation. The steam units at Moni and the gas turbines are mostly used for peak lopping. All stations use heavy fuel oil (HFO) for the steam plant and gasoil for the gas turbine plant.

The second phase of Vasilikos power station, which is under way, will comprise of a third steam unit using HFO with sulphur content of 1% and capacity of approximately 120 MWe. This is expected to be in operation in 2005. A seawater flue gas desulphurization plant [9] will be installed together with this third unit to limit the sulphur dioxide emissions at a level less than 100 mg/Nm^3. A review of the Cyprus existing generation system can be found in [10].

The technical characteristics of each generating unit are presented in Table 1. We observe that the first three steam units of Moni power station are expected to disconnect from the power system by the year 2006. Also, the steam plant of Moni power station is planned to withdraw by the year of 2011. The most efficient steam turbines are those of Vasilikos power station. The economic parameters of each generating unit are presented in Table 2. All data are based on the EAC actual costs derived from manpower, spares requirements, maintenance costs, unit availabilities and operation efficiencies.

3. Load forecasting

The principal function of electric load demand is the matching of generation output with consumer demand for a given decision making period. Because there is no storage of energy in power systems, generation at all times must equal the demand imposed by consumers in order to maintain the system frequency at its nominal value. Important attributes of the demand are (a) the forecast of the year-by-year peak load, (b) the forecast of the energy requirements on a year-by-year basis, (c) the forecast on the variation of the power value over the day, the week, and through the seasons of the year including dependence on the weather and (d) the reactive power values corresponding to active power values [13].

Table 1
Technical characteristics of existing generating units

Unit	Technology	Fuel type	Retirement year	Maximum net load (MWe)	Minimum operating load (MWe)	Heat rate at maximum load (kJ/kW h)	Heat rate at minimum load (kJ/kW h)	Average incremental heat rate (kJ/kW h)	Forced outage (%)	Yearly scheduled maintenance (days)
Moni power station										
ST1	Steam turbine	HFO (2% S)	2006	27	18	13,389	14,537	11,095	10.0	42
ST2	Steam turbine	HFO (2% S)	2006	27	18	13,389	14,537	11,095	10.0	42
ST3	Steam turbine	HFO (2% S)	2006	27	18	13,389	14,537	11,095	10.0	42
ST4	Steam turbine	HFO (2% S)	2007	27	18	13,389	14,537	11,095	10.0	42
ST5	Steam turbine	HFO (2% S)	2010	27	18	13,389	14,537	11,095	10.0	42
ST6	Steam turbine	HFO (2% S)	2011	27	18	13,389	14,537	11,095	10.0	42
GT1	Gas turbine	Gasoil	2012	37	13	11,549	16,023	9107	4.0	25
GT2	Gas turbine	Gasoil	2012	37	13	11,549	16,023	9107	4.0	25
GT3	Gas turbine	Gasoil	2014	37	13	11,549	16,023	9107	4.0	25
GT4	Gas turbine	Gasoil	2014	37	13	11,549	16,023	9107	4.0	25
Dhekelia power station										
ST1	Steam turbine	HFO (2% S)	2012	60	30	11,545	12,514	10,576	5.0	42
ST2	Steam turbine	HFO (2% S)	2013	60	30	11,545	12,514	10,576	5.0	42
ST3	Steam turbine	HFO (2% S)	2022	60	30	11,545	12,514	10,576	5.0	42
ST4	Steam turbine	HFO (2% S)	2022	60	30	11,545	12,514	10,576	5.0	42
ST5	Steam turbine	HFO (2% S)	2023	60	30	11,545	12,514	10,576	5.0	42
ST6	Steam turbine	HFO (2% S)	2023	60	30	11,545	12,514	10,576	5.0	42
Vasilikos power station										
ST1	Steam turbine	HFO (1% S)	2030	130	60	9016	9789	8354	4.0	28
ST2	Steam turbine	HFO (1% S)	2030	130	60	9016	9789	8354	4.0	28
GT1	Gas turbine	Gasoil	2020	37	13	11,549	16,023	9107	4.0	25

Table 2
Economic characteristics of existing generating units

Unit	Technology	Fuel type	Capacity (MWe)	Fixed O&M €/ kW month	Variable O&M €/MW h
Moni power station					
ST1	Steam turbine	HFO (2% S)	27	4.00	4.20
ST2	Steam turbine	HFO (2% S)	27	4.00	4.20
ST3	Steam turbine	HFO (2% S)	27	4.00	4.20
ST4	Steam turbine	HFO (2% S)	27	4.00	4.20
ST5	Steam turbine	HFO (2% S)	27	4.00	4.20
ST6	Steam turbine	HFO (2% S)	27	4.00	4.20
GT1	Gas turbine	Gasoil	37	1.25	6.00
GT2	Gas turbine	Gasoil	37	1.25	6.00
GT3	Gas turbine	Gasoil	37	1.25	6.00
GT4	Gas turbine	Gasoil	37	1.25	6.00
Dhekelia power station					
ST1	Steam turbine	HFO (2% S)	60	2.41	1.33
ST2	Steam turbine	HFO (2% S)	60	2.41	1.33
ST3	Steam turbine	HFO (2% S)	60	2.41	1.33
ST4	Steam turbine	HFO (2% S)	60	2.41	1.33
ST5	Steam turbine	HFO (2% S)	60	2.41	1.33
ST6	Steam turbine	HFO (2% S)	60	2.41	1.33
Vasilikos power station					
ST1	Steam turbine	HFO (1% S)	130	0.83	1.50
ST2	Steam turbine	HFO (1% S)	130	0.83	1.50
GT1	Gas turbine	Gasoil	37	1.25	6.00

Several main factors influence the demand, e.g., weather, working and holiday habits and the state of the economy. It is evident that a history of the demand and the pertinent external factors, going back over many years is invaluable. A processing of demand records is, therefore, fundamental in the approach to demand forecasting.

The load forecast used in this study is derived in terms of the net energy and demand requirements to be met by the generation. Unit auxiliary consumption is met by defining unit capacities and heat rates in sent out terms. In this manner units having high auxiliary consumption are penalized accordingly. The alternative approach, of predicting average auxiliary consumption and adding it into the load forecast, causes auxiliary consumption to be average across all generations, thus erroneously favouring the high consuming plant.

The load forecast for the period 2001–2020 is presented in Table 3 and in Fig. 3. Historical generation from the relevant figures for 2000, future energy requirements are estimated up until 2020 at declining growth rates. The demand figure in future years is obtained from the energy requirement by using a value of increase which decrease from 7.9% in 2001 to 4% in 2020 [4].

Table 3
Load forecast for the period 2001–2020

Year	Total generation (GW h)	Increase (%)	Peak load (MW)	Increase (%)
Actual				
1979	977.3		194	
1980	1034.4	5.8	198	2.1
1981	1060.1	2.5	199	0.5
1982	1140.3	7.6	226	13.6
1983	1206.2	5.8	237	4.9
1984	1249.9	3.6	239	0.8
1985	1319.2	5.5	254	6.3
1986	1422.6	7.8	256	0.8
1987	1502.6	5.6	268	4.7
1988	1648.1	9.7	293	9.3
1989	1832.0	11.2	330	12.6
1990	1974.6	7.8	360	9.1
1991	2077.1	5.2	401	11.4
1992	2404.2	15.7	460	14.7
1993	2581.1	7.4	480	4.3
1994	2710.5	5.0	485	1.0
1995	2473.1	−8.8	470	–3.1
1996	2592.0	4.8	493	4.9
1997	2710.5	4.6	532	7.9
1998	2953.9	9.0	577	8.5
1999	3139.2	6.3	621	7.6
2000	3373.6	7.5	688	10.8
Foreseen				
2001	3641.1	7.9	729	6.0
2002	3899.4	7.1	774	6.2
2003	4164.6	6.8	820	5.9
2004	4444.6	6.7	875	6.7
2005	4734.8	6.5	924	5.6
2006	5017.5	6.0	971	5.1
2007	5311.3	5.9	1028	5.9
2008	5617.0	5.8	1087	5.7
2009	5935.9	5.7	1139	4.8
2010	6268.6	5.6	1193	4.7
2011	6583.2	5.0	1253	5.0
2012	6904.3	4.9	1314	4.9
2013	7238.4	4.8	1377	4.8
2014	7584.8	4.8	1443	4.8
2015	7945.0	4.7	1512	4.8
2016	8271.8	4.1	1561	3.2
2017	8607.6	4.1	1624	4.0
2018	8953.9	4.0	1689	4.0
2019	9311.4	4.0	1743	3.2
2020	9680.6	4.0	1812	4.0

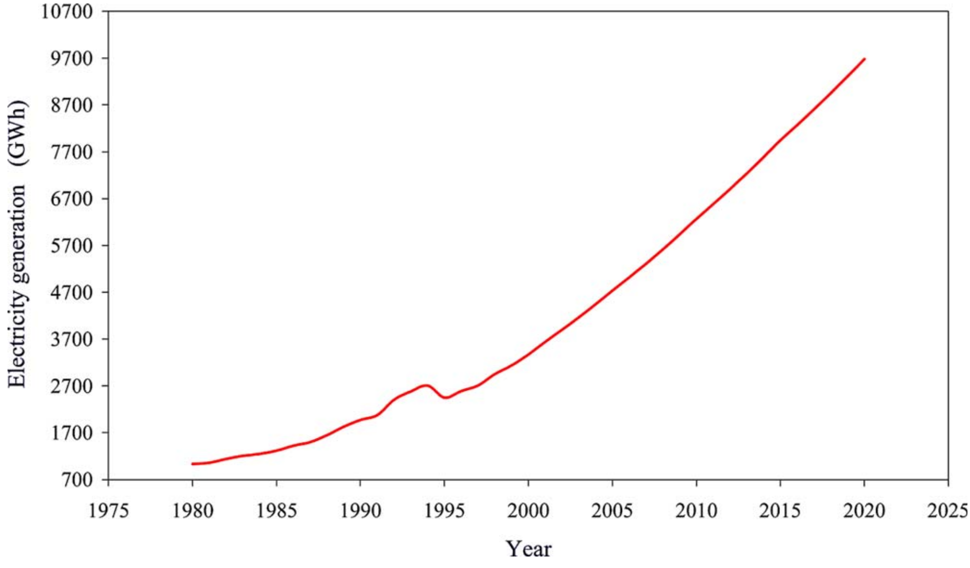

Fig. 3. Current and foreseen electricity generation.

4. Simulation of the power system

The future generation system of Cyprus power industry is simulated using the WASP package widely used in the public sector, for automatic generation planning. The WASP software package [20] finds the optimal expansion plan for a given power generating system over a period of up to 30 years [11]. The foreseen seasonal load duration curves, the efficiency, the maintenance period and the forced outage rate of each generating plant are taken into account. The objective function, which shows the overall cost of all generation system (existing and candidate generating plants), is composed of several components. The components, related to the candidate generating units, are the capital cost and the salvage capital cost. The components, which are related to both the existing and candidate generating units are the fuel cost, the fixed operation and maintenance costs, such as, staff cost, insurance charges, rates and fixed maintenance, the variable operation and maintenance costs, such as, spare parts, chemicals, oils, consumables, town water and sewage [16]. The cost to the national economy of the energy not served (ENS) because of shortage of capacity or interruptions is, also, taken into consideration [20].

Various generation options are examined, including LOTHECO cycle, in terms of economic, technical and environmental issues. The fuels considered include HFO, gasoil and natural gas. The technologies for future expansion of the Cyprus's generation system are thermal steam plant, gas turbine plant and combined cycle plant. Issue such as fuel quality, sources and costs as well as emissions

abatement equipment are all reviewed in [9]. Comparisons with the least cost generation option are made by means of parametric studies, where the results of LOTHECO cycle are tested for variations in principal parameters.

4.1. Generation system simulation

The WASP package was originally developed in the United States for the needs of the International Atomic Energy Agency (IAEA) [20]. It is the most frequently used and best-proven program for electric capacity expansion analysis in the public sector. It is used for long-term expansion planning for a period of up to 30 years and compares the total costs for the whole generation system for a number of candidate units. In the production simulation of WASP, a one-year period is divided into, at most, 12 sub-periods for each of which probabilistic simulation is applied. Equivalent load duration curves in the probabilistic simulation are approximated using Fourier series. The Fourier expansion makes it computationally simple to convolve and deconvolve generating units in the probabilistic simulation. The decision of the optimum expansion plan is made by the use of forward dynamic programming. The number of units for each candidate plant type that may be selected each year, in addition to other practical factors that may "constrain" the solution are specified. If the solution is limited by any such constraints, the input parameters can be adjusted and the model re-run. The dynamic programming optimization is repeated until the optimum solution is found. Each possible sequence of power units added to the system (expansion plan) meeting the constraints is evaluated by means of a cost function (the objective function), which is composed of (a) capital investment costs, *I*, (b) salvage value of investment costs, *S*, (c) fuel costs, *F*, (d) non-fuel operation and maintenance costs, *M*, and (e) cost of energy not served, Φ.

Thus,

$$B_j = \sum_{t=1}^{T} \left[I_{jt} - S_{jt} + F_{jt} + M_{jt} + \Phi_{jt} \right], \tag{1}$$

where B_j is the objective function attached to the expansion plan *j, t* is the time in years (1, 2,...,*T*) and *T* is the length of the study period (total number of years). All costs are discounted to a reference date at a given discount rate. The optimum expansion plan is the minimum B_j among all *j*.

The parameters used as data input to WASP are given in detail in [5,8]. For the existing generation system, actual data were used (for details see Section 2) and for the conventional candidate technologies data used in similar studies were considered, as illustrated in Tables 4 and 5. In the case of LOTHECO cycle, a parametric study involving the cycle efficiency from 50% to 70% and the capital cost from 700 to 900 €/kW were examined. The fuel prices used can, also, be found in Table 5. A discount rate of 6% and inflation of 3% were considered with an ENS value of 3 €/kW h.

Table 4
Candidate technologies technical parameters

Option no.	Technology	Fuel type	Maximum net load (MWe)	Minimum operating load (MWe)	Heat rate at maximum load (kJ/kW h)	Heat rate at minimum load (kJ/kW h)	Average incremental heat rate (kJ/kW h)	Forced outage (%)	Yearly scheduled maintenance (days)
1	Boiler/steam turbine	HFO (1% S)	112	48	9663	11,179	8526	4.0	28
2	Combined cycle	Natural gas	180	72	7201	9998	5337	4.0	15
3	Combined cycle	Gasoil	180	72	7616	9998	6028	4.0	27
4	Gas turbine	Natural gas	81	28	12,686	17,698	10,038	4.0	25
5	LOTHECO cycle	Natural gas	180	72	7200	9998	5335	5.2	20
6	LOTHECO cycle	Natural gas	180	72	6000	8333	4445	5.2	20
7	LOTHECO cycle	Natural gas	180	72	5143	7140	3812	5.2	20

Table 5
Candidate technologies economic parameters

Option no.	Technology	Fuel type	Capacity (MWe)	Capital cost (€/kW)	Fuel net calorific value (GJ/t)	Fuel cost		Fixed O&M (€/kW month)	Variable O&M (€/MW h)
						€/t	€/GJ		
1	Boiler/steam turbine	HFO (1% S)	112	1258	41.3	125	3.03	1.40	1.50
2	Combined cycle	Natural gas	180	686	45.0	141	3.13	1.25	2.50
3	Combined cycle	Gasoil	180	707	42.5	190	4.47	1.57	3.20
4	Gas turbine	Natural gas	81	532	45.0	141	3.13	0.83	4.00
5	LOTHECO cycle	Natural gas	180	700	45.0	141	3.13	1.63	3.25
6	LOTHECO cycle	Natural gas	180	800	45.0	141	3.13	1.63	3.25
7	LOTHECO cycle	Natural gas	180	900	45.0	141	3.13	1.63	3.25

4.2. Results

In all 13 runs, an HFO steam turbine unit assumed to be installed in 2005 and thereafter WASP was free to choose the years for installing the candidate technology in each run. The time horizon was 30 years 2002–2031, with the year 2002 being the base year. For the last 10 years of the planning period, no growth of demand was assumed and therefore no addition or retirement of units, in order to avoid end-effects.

The projected cost of the generation system by the installation of the various candidate technologies is presented in Table 6 and the diagrammatic ranking order of the results is illustrated in Fig. 4. In the case of conventional technologies, we observe that the least cost power generation scheme is the combined cycle with natural gas as a fuel (2.66 €/kW h). By comparing the conventional natural gas combined cycle with the various LOTHECO cycle parametric studies, we observe that in the cases of LOTHECO cycle with (a) efficiency of 60% and capital cost of 800–900 €/kW and (b) efficiency of 50% and capital cost of 700 €/kW the results are marginal compared to that obtained from the use of conventional natural gas combined cycle. It is, therefore, clear that for efficiencies greater than 60% and capital cost between 700 and 900 €/kW, LOTHECO cycle is the least cost generation technology.

5. Independent power producers analysis

The analysis is carried out using the IPP optimization algorithm [16]. This user-friendly software tool takes into account the capital cost, the fuel cost and operation and maintenance requirements of each candidate scheme and calculates the least cost configuration and the ranking order of the candidate power technologies.

Table 6
Projected cost of generation system

No.	Technology	Electricity unit cost (€c/kW h)
1	LOTHECO, 700 €/kW, $\eta = 70\%$	2.54
2	LOTHECO, 800 €/kW, $\eta = 70\%$	2.59
3	LOTHECO, 700 €/kW, $\eta = 60\%$	2.61
4	LOTHECO, 900 €/kW, $\eta = 70\%$	2.65
5	Combined cycle, natural gas	2.66
6	LOTHECO, 800 €/kW, $\eta = 60\%$	2.67
7	LOTHECO, 700 €/kW, $\eta = 50\%$	2.71
8	LOTHECO, 900 €/kW, $\eta = 60\%$	2.72
9	LOTHECO, 800 €/kW, $\eta = 50\%$	2.77
10	LOTHECO, 900 €/kW, $\eta = 50\%$	2.83
11	Gas turbine, natural gas	2.93
12	Combined cycle, gasoil	2.96
13	Boiler/steam turbine, HFO	2.99

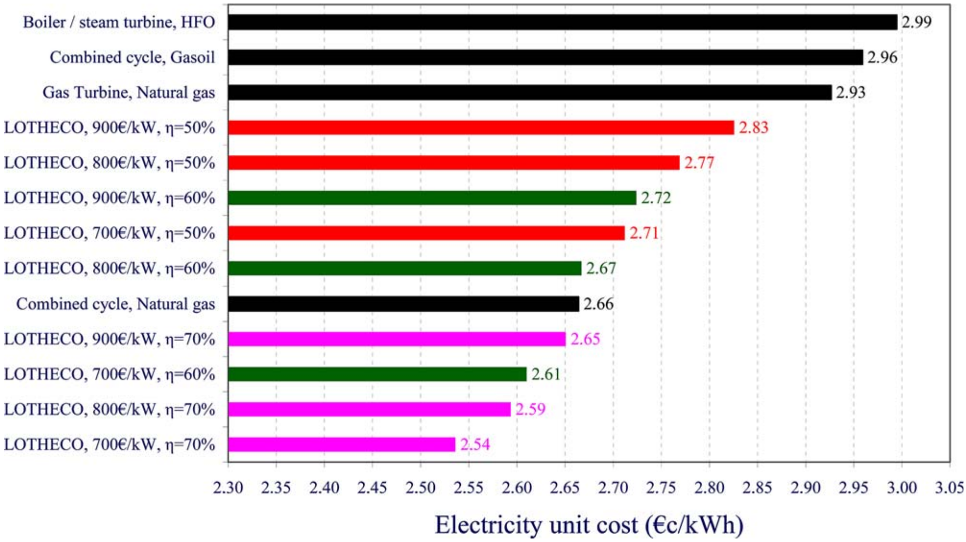

Fig. 4. WASP results.

5.1. Economic parameters of power generation technologies

The costs associated with building and operating power plants are (a) capital cost with the provision of infrastructure such as coal jetties, LNG (liquefied natural gas) facilities, HFO storage tanks, etc. (b) fuel cost, (c) fixed O&M cost, such as, staff costs, insurance charges, rates and fixed maintenance and (d) variable O&M cost, such as, spare parts, chemicals, oils, consumables, town water and sewage. The contribution of capital recovery cost varies between 30% and 50% of the electricity unit cost, depending on several variables like plant size, site, technology type, etc. Fuel cost is usually the major component cost over the useful service life of power plants. The relative impact of fuel prices on total costs over the plants lifetime varies according to the candidate technology. Choices of price assumptions is therefore of great importance as to identify relative competitiveness between different types of power technologies. The O&M cost ranges between 15% and 30%, depending mainly on plant capacity and plant technology.

The reliability of the continuing trouble free operation of power plant is a key consideration related directly to the electricity production cost. The reliability of any power plant is a function of proper operation and good design. Proper operation depends on operators' experience, skills and training. Good design should compensate for or prevent operation errors, through sufficient instrumentation and control. Computer and digital controls allow full plant automation, which is highly desirable to increase reliability of large plants. With good design and operation, plant availability may exceed 95% of the time over one year. All plants need some shutdown time for routine maintenance, which accounts for the remaining percentage. A common approach to increase plant availability is to have spares or

duplicate copies of key items installed or in store ready for use when the operating item fails.

The useful service life of a power plant is defined as the years over which the plant produces the electricity quantity it is designed for. Power plants are designed for a service life of 25–30 years. The selection of material and equipment specification can greatly impact the capital and the O&M cost required over the life of the plant. Plant automation will reduce the cost of labour with the additional advantage of increased plant reliability.

5.2. Mathematical formulation and optimization algorithm

The general electricity unit cost c in €/kW h, in current prices, for the candidate technology k, is given by

$$c_k = \left[\frac{C_0 + \sum_{j=1}^{n} C_j/(1+i)^j}{P_0 + \sum_{j=1}^{n} P_j/(1+i)^j} \right]_k, \tag{2}$$

where C_0 is the production cost of the reference year in € (e.g., for current prices the year 2003), P_0 is the electricity production of the reference year in kW h, C_j is the production cost of the year j, $j = 1, 2, \ldots, n$, in €, P_j is the electricity production of the year j, $j = 1, 2, \ldots, n$, in kW h and i is the discount rate.

The annual production cost from each candidate technology C_j in € is calculated by

$$C_j = C_{Cj} + C_{Fj} + C_{OMj}, \tag{3}$$

where C_{Cj} is the capital cost which can be amortized, for example, during the construction period of each candidate plant. Also, C_{Fj} is the annual fuel cost in €, which can be determined by the relation

$$C_{Fj} = 3.15 \times 10^6 \times \left(\frac{F_j \times P_c \times \mathrm{LF}}{\eta \times \mathrm{CV}} \right), \tag{4}$$

where F_j is the fuel cost in €/t, P_C is the installed capacity of the candidate technology in MWe, LF is the load factor in %, η is the efficiency in % and CV is the fuel calorific value in kJ/kg.

The annual O&M cost C_{OMj} in € is given by

$$C_{OMj} = C_{OMFj} + C_{OMVj}, \tag{5}$$

where C_{OMFj} is the annual fixed O&M cost in € and C_{OMVj} is the variable O&M cost in €.

The fixed O&M cost is given by

$$C_{OMj} = 12 \times O_{MFj} \times P_c, \tag{6}$$

where O_{MFj} is the monthly fixed O&M in €/kW month. The variable O&M is given by

$$C_{OMVj} = 8760 \times O_{MVj} \times P_c \times LF, \tag{7}$$

where O_{MVj} is the variable O&M cost in €/kW h.

The annual electricity production P_j in kW h is given by the relation

$$P_j = 8760 \times P_c \times \mathrm{LF}. \tag{8}$$

The optimum solution can then be obtained by

$$\text{least cost solution} = \min[c_k]. \tag{9}$$

Details of the optimization algorithm implementing the above mathematical formulation can be found in [16]. The algorithm takes into account the capital cost, the fuel consumption and cost, operation cost, maintenance cost, discount rate, plant load factor, etc. All costs are discounted to a reference date at a given discount rate. Each run can handle 30 different candidate schemes simultaneously. Based on the above input parameters for each candidate technology, the algorithm calculates the least cost power generation configuration in current prices and the ranking order of the candidate schemes.

5.3. Results

A range of eligible conventional power generation technologies were taken into account. The technical and economic parameters examined are shown in Table 7. In the case of LOTHECO cycle, a parametric study involving the cycle efficiency from 50% to 70% and the capital costs from 700 to 900 €/kW were examined. The capital costs, including infrastructure costs, have been estimated for each scheme at 2002 price levels and have been amortized during the construction period of each candidate technology. Infrastructure costs for an HFO and gasoil plants include the unloading pipeline and the storage tanks. In the case of natural gas, these costs are included in the fuel price. Choice of fuel price assumptions is of great importance in order to identify relative competitiveness between different types of power technologies. The fuel prices used are illustrated in Table 7. A discount rate of 6% was, also, considered.

The results obtained, for different values of load factor, are shown in Table 8 and Figs. 5 and 6. In the case of conventional technologies, Fig. 5, we observe that the least cost power generation scheme is the combined cycle with natural gas as a fuel, e.g., for a load factor of 80%, the specific cost is 3.49 €/kW h. Referring to Fig. 6, we compare the natural gas combined cycle with the various LOTHECO cycle parametric studies. It is clear that for efficiencies greater than 60% and capital cost between 700 and 900 €/kW, LOTHECO cycle is the least cost generation technology.

Table 7
Input parameters of different power generation candidate technologies

Option no.	Technology	Fuel type	Capacity (MWe)	Capital cost (€/kW)	Efficiency (%)	Fuel net calorific value (GJ/t)	Fuel cost		Fixed O&M (€/kW month)	Variable O&M (€/MW h)
							€/t	€/GJ		
1	Boiler/steam turbine	HFO (1% S)	120	1258	37.26	41.3	125	3.03	1.40	1.50
2	Combined cycle	Natural gas	180	686	50.00	45.0	141	3.13	1.25	2.50
3	Combined cycle	Gasoil	180	707	47.27	42.5	190	4.47	1.57	3.20
4	Gas turbine	Natural gas	81	532	28.38	45.0	141	3.13	0.83	4.00
5	LOTHECO cycle	Natural gas	180	700	50.00	45.0	141	3.13	1.63	3.25
6	LOTHECO cycle	Natural gas	180	700	60.00	45.0	141	3.13	1.63	3.25
7	LOTHECO cycle	Natural gas	180	700	70.00	45.0	141	3.13	1.63	3.25
8	LOTHECO cycle	Natural gas	180	800	50.00	45.0	141	3.13	1.63	3.25
9	LOTHECO cycle	Natural gas	180	800	60.00	45.0	141	3.13	1.63	3.25
10	LOTHECO cycle	Natural gas	180	800	70.00	45.0	141	3.13	1.63	3.25
11	LOTHECO cycle	Natural gas	180	900	50.00	45.0	141	3.13	1.63	3.25
12	LOTHECO cycle	Natural gas	180	900	60.00	45.0	141	3.13	1.63	3.25
13	LOTHECO cycle	Natural gas	180	900	70.00	45.0	141	3.13	1.63	3.25

Table 8
Results obtained using the optimization algorithm for independent power producers

Option no.	Technology	Fuel type	Capital cost (€/kW)	Efficiency (%)	Load factor				
					50%	60%	70%	80%	90%
					Electricity unit cost (€c/kW h)				
1	Boiler/steam turbine	HFO	1258	37.36	5.57	5.15	4.85	4.63	4.46
2	Combined cycle	Natural gas	686	50.00	4.09	3.82	3.63	3.49	3.38
3	Combined cycle	Gasoil	707	47.27	5.43	5.15	4.94	4.79	4.67
4	Gas turbine	Natural gas	532	28.38	5.56	5.36	5.22	5.12	5.03
5	LOTHECO cycle	Natural gas	700	50.00	4.29	4.01	3.80	3.65	3.53
6	LOTHECO cycle	Natural gas	700	60.00	3.91	3.63	3.43	3.27	3.15
7	LOTHECO cycle	Natural gas	700	70.00	3.65	3.36	3.16	3.00	2.89
8	LOTHECO cycle	Natural gas	800	50.00	4.47	4.16	3.93	3.76	3.63
9	LOTHECO cycle	Natural gas	800	60.00	4.09	3.78	3.55	3.39	3.25
10	LOTHECO cycle	Natural gas	800	70.00	3.83	3.51	3.29	3.12	2.99
11	LOTHECO cycle	Natural gas	900	50.00	4.65	4.31	4.06	3.87	3.73
12	LOTHECO cycle	Natural gas	900	60.00	4.27	3.93	3.68	3.50	3.35
13	LOTHECO cycle	Natural gas	900	70.00	4.01	3.66	3.41	3.23	3.09

6. Emissions

The power industry is one of the few industrial sectors, which affect prosperity of every sphere of economic and social life and exert a direct influence on general technological progress. At the same time, the industry must concern itself with the

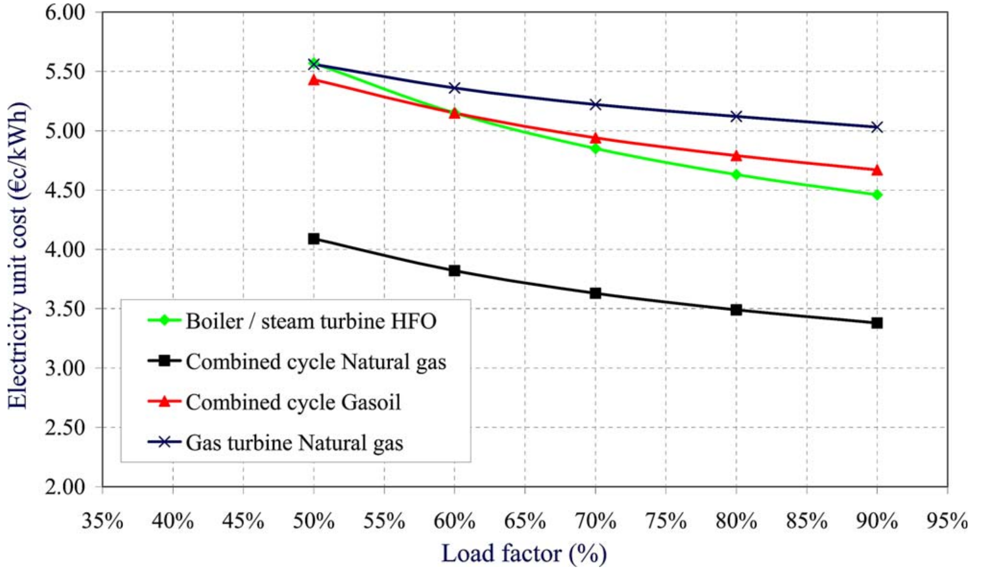

Fig. 5. Conventional power technologies ranking order.

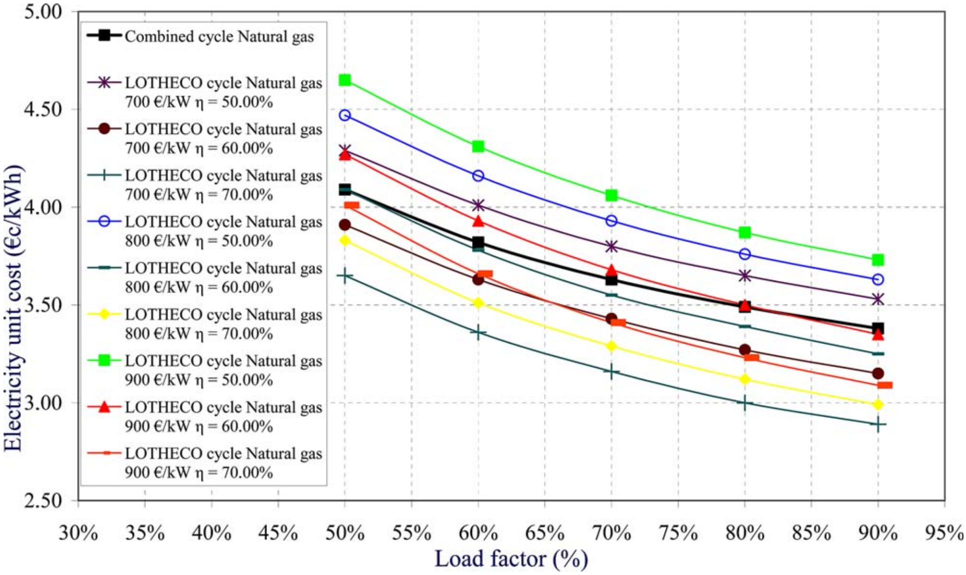

Fig. 6. LOTHECO cycle parametric study.

negative impact of power stations on the environment, which is an issue that has to be faced squarely. The environmental indicators of power stations significantly influence national environmental policy and are important element in environmental protection over the world. Thermal power stations account for approximately 50% of the total volume of pollutants released into the atmosphere by industry and transport in Cyprus. For this reason, environmental control in the power industry has been enforced by the competent authority. National standards on permissible emissions of atmosphere pollutants have been adopted which are no less rigorous than those adopted in a number of industrially developed countries [1], [21].

Quantitative monitoring of pollutant emissions at plants is carried out in accordance with the regulations on control of atmospheric emissions at thermal power stations. Rules governing environmental control at individual power station are coordinated with the competent authority. These rules pinpoint the sources of the emissions and indicate the substances being monitored, the methodology and the periodicity of monitoring. The quantities measured are noted in a register of emissions and discharges into the environment. All substances for which appropriate and valid standards have been devised are subject to monitoring. The results are recorded in annual reports subsequently sent to the competent authority.

6.1. Current state

The power industry in Cyprus is characterized by a relatively large annual increase in electricity generation. A total of 3325 GW h of electricity was generated in 2000, which represents an increase of 72% for the period 1990–2000 with an

average increase of 7.2% per year. For the period 1980–1990, the increase was 91% with an average annual increase of 9.1%.

From the environment point of view, the impact on atmospheric air from the power stations is long-term (measurable in decades) through the emission of products of combustion. The positive trend of recent years, namely lower emissions of atmospheric pollutants from thermal power stations is the result of the use of high quality and, thus, more expensive, HFO [15].

Analysis of the data shows that a reduction in pollutant emissions has been achieved through qualitative improvements in the operation of thermal power stations. The environmental indicators [3] in contrast to the annual quantities of emissions, which principally illustrate the type of fuel used at thermal power stations, environmental indicators measure the station operating efficiency as well for the period 1980–2010 are presented in Table 9 (and Fig. 7), where it can be observed that during the period 1990–2000 there was a decrease of 33% of the sulphur dioxide indicator. Also, during this period there was a decrease of 30% in particulates indicator. Of course, the main reason for this positive trend is the commissioning of more efficient generating plants and the use of better quality HFO.

It is widely known that carbon dioxide (CO_2), as one of the products of fossil fuel combustion, is particularly harmful to the earth's climate. The threat to the climate is a global problem, and the topicality of the issue is inextricably bound with the nature of energy production and consumption. The adoption of the United Nations Framework Convention on Climate Change by a significant proportion of States reaffirms the international community's awareness of the problem and its unanimous desire to avert potential global disasters. The States parties to the Convention have committed themselves to stabilizing CO_2 emissions by the year 2000 at levels not exceeding those of 1990. The first major United Nations Conference on Environment was held in Rio 1992, the so-called Earth Summit. Industrialized countries agreed to bring their emissions of greenhouse gases back to 1990 levels by the year 2000. Cyprus committed to a differentiated set of measures, which include adopting national policies and taking corresponding measures on the mitigation of climate change. To date, more than 160 Nations are parties to the Climate Convention. The Climate Convection has given rise to the Kyoto Protocol, which was agreed in December 1997, after the Conference of Parties has stated in

Table 9
Actual primary emissions and carbon dioxide environmental indicators for the period 1980–2000

Emission	Year	
	1990 (decrease over 1980 emissions) (%)	2000 (decrease over 1990 emissions) (%)
SO_2	–6	–33
NO_x	–17	–3
Particulates	–50	–30
CO_2	–9	–1

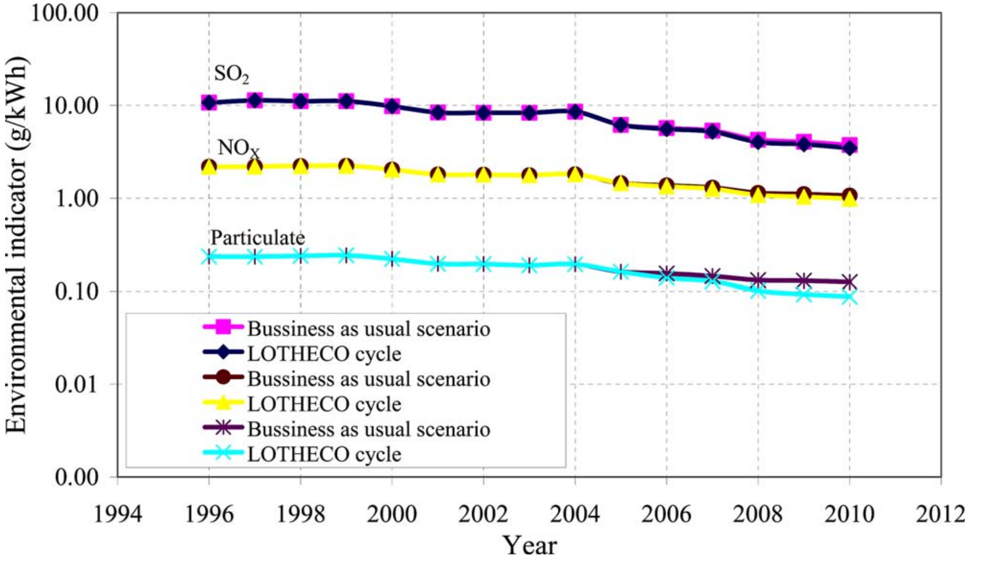

Fig. 7. Current and foreseen principal emissions' environmental indicators.

Berlin in 1995 that the commitment taken so far had not been sufficient. The Kyoto Protocol legally binds the industrialized countries to quantify emission limitation and reductions in the time frame from 2008 until 2012.

Table 9 and Fig. 8 shows the overall trends in thermal power stations CO_2 emissions during the period 1980–2010. During the 1900s, over a period of 10 years, the CO_2 environmental indicator decreased only by 1% compared to the 1990 figure and by 10% decrease compared to 1980 figure as shown in Table 8. The minor improvement on the environmental indicator for carbon dioxide points to certain positive quality enhancements in the energy production structure and the quality of the fuel consumed.

6.2. Prospects for the improvement of environmental indicators

It is estimated that electricity output in Cyprus will increase to 4735 GW h by 2005 and to 6268 GW h by 2010 (see Fig. 3). The foreseen principle pollutant (SO_2, NO_X and particulates) and CO_2 emissions environmental indicators are summarized in Table 10 and Figs. 7 and 8.

Based on the business as usual scenario, i.e., expansion of the generation system with steam turbines, and despite the increase in energy output in Cyprus, the foreseen environmental indicators of the principal pollutants will be further reduced. Reduction of the negative impact of thermal power stations on the environment over the period 2000–2010 will depend on (a) a change in better quality fuel, (b) the elimination from the balance of obsolete, uneconomic and environmentally 'dirty' plant and (c) the introduction of new, environmentally clean and efficient plant that satisfies modern requirements. The possible introduction of LOTHECO

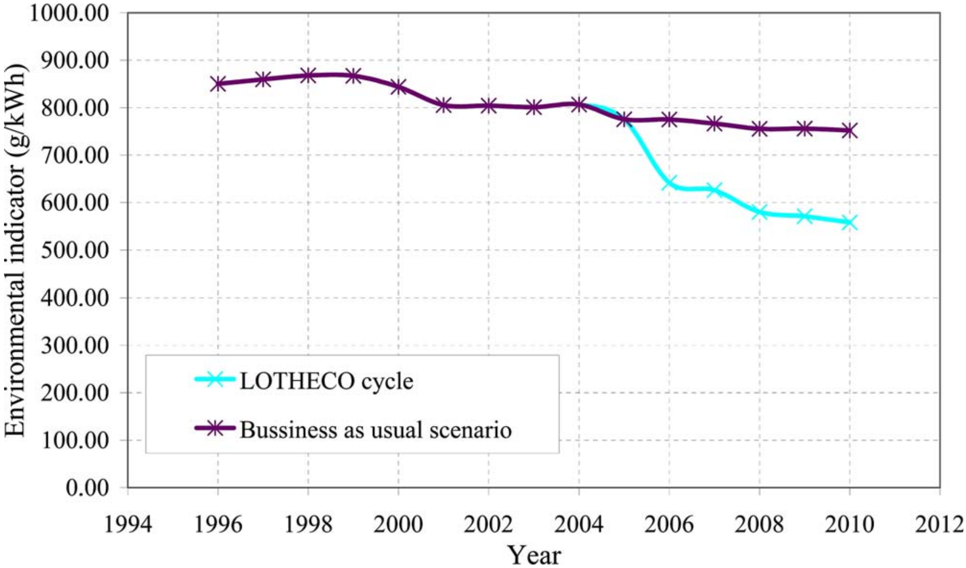

Fig. 8. Current and foreseen carbon dioxide environmental indicator.

Table 10
Foreseen primary emissions and carbon dioxide environmental indicators for the period 2000–2010

Emission	Year 2010	
	Business as usual scenario, decrease over 2000 emissions (%)	LOTHECO cycle, $\eta = 60\%$, decrease over 2000 emissions (%)
SO_2	–28	–33
NO_x	–2	–9
Particulates	7	–26
CO_2	68	24

cycle plants to the generation system will, also, have a positive impact on the environmental indicators as indicated in Table 10 and Figs. 7 and 8. By the use of LOTHECO cycle instead of the business as usual scenario, the principal environmental indicators would be reduced by the year 2010 by approximately −23% instead of −8%. Further, the carbon dioxide environmental indicator will be reduced by +24% instead of +68%.

7. Conclusions

In this work a cost–benefit study concerning the use of the LOTHECO cycle by independent power producers in Cyprus was carried out. Also, comparisons were made through commercial software. Further, the expected main emissions from the LOTHECO cycle were compared with existing commercial technologies.

In particular, the future generation system of Cyprus powers industry was simulated by an IPP optimization algorithm [16] and by WASP [11]. Various conventional generation options were examined and compared with LOTHECO cycle parametric study. The economic analysis, based on the assumptions used and the candidate technologies examined, indicated that in the case of conventional technologies the least cost solution is the natural gas combined cycle. Additional computer runs with the various LOTHECO cycle parametric studies indicated that for efficiencies greater than 60% and capital cost between 700 and 900 €/kW, LOTHECO cycle is the least cost generation technology.

The current state and future improvements of the environmental indicators of the power industry in Cyprus were presented. It was estimated that by the use of LOTHECO cycle instead of the business as usual scenario the principal environmental indicators would be reduced by the year 2010 by approximately −23% instead of −8%. Further, the carbon dioxide environmental indicator will be reduced by +24% instead of +68%.

Acknowledgements

This work has been partially funded by the Fifth Framework Program of Research and Development of the European Union, Contract No.: ENK5-CT2000-00063.

References

[1] Clinch JP, Healy JD. Domestic energy efficiency in Ireland: correcting market failure. Energy Policy 2000;28:1–8.

[2] Combined Cycle Power Plant with Integrated Low Temperature (LOTHECO), Contract No. ENK5-CT2000-00063, Fifth Framework Program of Research, Development and Demonstration, European Union (2002–2003).

[3] Dale VH, Beyeler SC. Challenges in the development and use of ecological indicators. Ecological Indicators 2001;1:3–10.

[4] Electricity Authority of Cyprus. EAC Annual Report, 2001.

[5] Eliopoulos C, Kellas A, Stylianou S, Stephanou A, Theophanous A, Pattichis P, Poullikkas A. Optimisation of the generation system expansion. Electricity Authority of Cyprus; 1999 (in Greek).

[6] Franco A, Russo A. Combined cycle plant efficiency increase based on the optimization of the heat recovery steam generator operating parameters. International Journal of Thermal Sciences 2002;41:843–59.

[7] Grainger J, Stevenson W. Power system analysis. McGraw Hill; 1994.

[8] Kellas A, Poullikkas A. Least cost generation system expansion study. Generation Department, Electricity Authority of Cyprus; 1998 (in Greek).

[9] Kellas A, Poullikkas A. Flue gas desulphurisation (FGD) systems—design, operating and financial considerations. Generation Department, Electricity Authority of Cyprus; 1999.

[10] Kellas A. The use of WASP model and the generation system development in Cyprus. Proceedings of the 10th Mediterranean Electrotechinical Conference, 3. 2000, p. 1036–9.

[11] Kellas A, Poullikkas A. Cyprus future generation system. Proceedings of the 3rd Mediterranean Conference on Power Generation, Transmission, Distribution and Energy Conversion. 2002.

[12] Nahman J, Peric D. Analysis of cost of urban medium voltage distribution networks. International Journal of Electrical Power and Energy Systems 1998;20:7–16.
[13] Poullikkas A. A least squares method for electric load forecasting. The Cyprus Journal of Science and Technology 1997;1/3:105–8.
[14] Poullikkas A. Two phase flow performance of nuclear reactor cooling pumps. Progress in Nuclear Energy 2000;36:123–30.
[15] Poullikkas A. The price of population. Power Engineering International 2001;4:16–18.
[16] Poullikkas A. A technology selection algorithm for independent power producers. The Electricity Journal 2001;14/6:80–4.
[17] Skorzki BGA, Vopat WA. Power station engineering and economy. McGraw Hill; 1960.
[18] Weedy BM, Cory BJ. Electric power systems. Wiley; 1998.
[19] Weron R, Przybylowicz B. Hurst analysis of electricity price dynamics. Physica A 2000;283:462–8.
[20] Wien Automatic System Planning Package (WASP). A computer code for power generating system expansion planning. International Atomic Energy Agency, 1980.
[21] Zhicheng C, Porter R. Energy management and environmental awareness in China's enterprises. Energy Policy 2000;28:49–63.